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September 23, 2019

Via Electronic Filing

The Honorable Jocelyn G. Boyd
Chief Clerk/Administrator
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, SC 29210

Re: South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Dominion Energy South Carolina, Incorporated's Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) - S.C. Code Ann. Section 58-41-20(A)

Docket Number 2019-184-E

Dear Ms. Boyd:

Please find attached for electronic filing the Direct Testimony of Derek P. Stenclik filed on behalf of the South Carolina Coastal Conservation League (CCL) and Southern Alliance for Clean Energy (SACE) in the above-referenced matter. Please contact me if you have any questions concerning this filing.

Sincerely,

/s/ Stinson W. Ferguson

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*Attorney for South Carolina Coastal
Conservation League and Southern Alliance
for Clean Energy*

Enclosures
SWF/ees
cc (w/encl.): Parties of Record

STATE OF SOUTH CAROLINA
BEFORE THE PUBLIC SERVICE COMMISSION
DOCKET NO. 2019-184-E

In re: South Carolina Energy)
Freedom Act (H.3659) Proceeding to)
Establish Dominion Energy South)
Carolina, Incorporated's Standard)
Offer, Avoided Cost Methodologies,)
Form Contract Power Purchase)
Agreements, Commitment to Sell)
Forms, and Any Other Terms or)
Conditions Necessary (Includes)
Small Power Producers as Defined in)
16 United States Code 796, as)
Amended) - S.C. Code Ann. Section)
58-41-20(A))

CERTIFICATE OF SERVICE

I certify that the following persons have been served with one (1) copy of the Direct Testimony of Derek P. Stenlik by electronic mail and/or U.S. First Class Mail at the addresses set forth below:

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This the 23rd day of September, 2019.

**DIRECT TESTIMONY OF
DEREK P. STENCLIK
SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND
SOUTHERN ALLIANCE FOR CLEAN ENERGY
DOCKET NO. 2019-184-E**

INTRODUCTION

1

2 **Q: Please state your name, position, and business address for the record**

3 A: My name is Derek Stenclik and I am currently President of Telos Energy,
4 Inc. My business address is 475 Broadway, Unit 6, Saratoga Springs, NY 12866.

5

6 **Q: Please summarize your professional and educational qualifications.**

7 A: I am the founding partner of Telos Energy, Inc., an analytics and
8 technology company specializing in grid technologies that enable renewable
9 integration. I have a decade of experience helping clients across the electric power
10 industry navigate evolving markets, adapt to rapidly changing technologies, and
11 accelerate clean energy integration. I specialize in production cost modeling for
12 deregulated power markets, wind and solar integration, and battery energy
13 storage.

14 From 2011 to 2018, I was employed by GE Energy Consulting, most
15 recently as the Senior Manager of Power Systems Strategy. In that role I was
16 responsible for a team of engineers and economists that conducted economic and
17 transmission planning studies for utilities, grid operators, and developers across
18 North America. I was also responsible for the group's renewable integration
19 practice where I conducted over a dozen large-scale, multi-year wind and solar
20 integration studies.

1 I hold a master's degree in Applied Economics and Management from
2 Cornell University and graduated with Summa Cum Laude and Phi Beta Kappa
3 honors from State University of New York, College at Geneseo. Additional
4 qualifications are included in Exhibit A.

5
6 **Q: Have you previously filed testimony as an expert witness in a regulatory**
7 **proceeding?**

8 A: Yes, I have filed expert testimony before the Canadian House of
9 Commons Standing Committee on Natural Resources. This is my first time
10 appearing before the Public Service Commission of South Carolina.

11
12 **Q: On whose behalf are you testifying in this proceeding?**

13 A: I am submitting this testimony on behalf of The South Carolina Coastal
14 Conservation League and the Southern Alliance for Clean Energy.

15
16 **Q: Are you sponsoring any exhibits?**

17 A: Yes, attached to my testimony is an Expert Report titled "Analysis of
18 Dominion Energy South Carolina's Proposed Variable Integration Charge,"
19 included in Exhibit B. My qualifications are included in Exhibit A.

20
21 **Q: What is the purpose of your direct testimony in this proceeding?**

22 A: The purpose of my direct testimony in this proceeding is to review and
23 evaluate DESC's proposed Variable Integration Charge. I discuss problems with

1 the methodology used to develop the proposed Variable Integration Charge and
2 recommend that the Commission reject the charge as unsupported and
3 inappropriate at this time.

4 **REVIEW OF VARIABLE INTEGRATION CHARGE AND CONCLUSIONS**

5 **Q: Please provide a brief overview of DESC's proposed Variable Integration**
6 **Charge.**

7 A: DESC's proposed Variable Integration Charge is based on an analysis that
8 purports to determine an amount of additional operating reserves that DESC must
9 carry in order to compensate for potential errors in the solar forecast. It also
10 purports to quantify the cost of providing those reserves through the use of
11 production cost modeling of DESC's system.

12
13 **Q: Have you reviewed DESC's witness testimony regarding the proposed**
14 **variable integration charge?**

15 A: Yes, I reviewed the Direct Testimony of Matthew W. Tanner, Ph.D., and
16 the report *Cost of Variable Integration*, Navigant Consulting, August 2019,
17 Exhibit No. (MWT-2), attached to the testimony. I have also reviewed supporting
18 testimony from DESC staff that is relevant to the proposed Variable Integration
19 Charge including Direct Testimony of Eric H. Bell, Direct Testimony of John H.
20 Raftery, and Direct Testimony and Exhibits of Joseph M. Lynch.

21
22 **Q: What is your reaction to that testimony and DESC's proposal?**

1 A: The basic premise that adding variable renewable generation to the power
2 system may increase some aspects of operating costs, as stated by Dr. Tanner's
3 testimony, is not unreasonable. The use of hourly production cost modeling and
4 comparing cases with and without additional solar generation is also generally
5 accepted by the industry. However, DESC's analysis incorrectly analyzes solar
6 data and therefore overstates the associated utility reserve requirements in its
7 modeling. DESC should update its analysis method and tools to reflect actual
8 utility reliability requirements, capabilities, and operations. DESC should
9 reanalyze its solar data to reflect plant, forecasting, and system aggregation
10 benefits. Until these problems are addressed, the costs of variable integration
11 developed in the Cost of Variable Integration study will be overstated and will not
12 reflect actual increased reserve requirements or actual impacts on the operating
13 costs that DESC will likely experience as a result of increased solar generation.

14 While the proposed reserve requirements may be appropriate for long-
15 term planning studies, basing actual variable integration charges only on
16 modeling analyses, without supporting operational experience, is adding an
17 expense that has not yet been incurred. As a result, it is premature to add
18 contractual costs on long-term PPAs until more is known about the actual
19 operational requirements needed by DESC.

20
21 **Q: Please provide an overview of the primary issues you have identified with the**
22 **Cost of Variable Integration study DESC has presented.**

1 A: I have several concerns with the Cost of Variable Integration study DESC
2 has presented in the Cost of Variable Integration analysis. A brief summary of the
3 main concerns is provided below, with additional clarification provided in Exhibit
4 B.

5 First, the analysis assumed inappropriately high reserve requirements. This
6 is because the modeling and planning analyses do not accurately capture current
7 operating practices, which does not currently require operating reserves for
8 existing solar generation. In addition, the analysis failed to account for
9 aggregation benefits that naturally reduce the relative forecasting errors and
10 resource variability as the solar generation fleet grows. The analysis also used an
11 excessive 4-hour ahead forecast, overstating the forecast error that may impact
12 actual operations. The 4-hour ahead solar forecast error also did not include off-
13 line combined cycle (CC) generation capacity as available reserves. Finally, the
14 operating reserve methodology used an overly stringent 99% confidence interval
15 (covering all but 1% of solar forecast errors), which overstates the required
16 operating reserves.

17 Second, there are several concerns with the modeling methodology
18 implemented in the study. Most troubling is that additional fixed solar reserve
19 requirements were imposed 8,760 hours a year rather than being a function of the
20 hourly forecasted solar generation, greatly overstating additional reserve costs.
21 The analysis also failed to include significant additional reserve capability from
22 the Fairfield Pumped Storage plant and from interruptible load that are
23 appropriately available as solar forecast error reserves. Fairfield Pumped Storage

1 should be operated optimally to better integrate renewable energy and ultimately
2 benefit ratepayers. A flawed analysis that undercounts this resource and other
3 available integration capacity could, if acted upon, unnecessarily impose costs and
4 duplicate capacity that is not necessary. Lastly, neighboring power systems were
5 not properly accounted for in the analysis, thereby eliminating an economic
6 resource regularly utilized by DESC. This omission greatly overstates additional
7 reserve costs.

8 Third, DESC failed to evaluate less costly methods of integrating low-cost
9 renewable resources. For instance, DESC did not include existing demand
10 response resources to the full extent possible, eliminating a valuable source of
11 operating reserves from the analysis. In addition, DESC failed to evaluate the full
12 range of services that could be provided by new battery energy storage and CT
13 units, thereby overstating the cost to implement these resources as a mitigation
14 option. Lastly, DESC did not evaluate the potential to reduce ratepayer costs
15 through participation in a larger balancing area or by implementing new demand
16 response, flexible solar, combined cycle upgrades, and discounting of solar
17 forecasts.

18 Fourth, variable integration charges targeted at a specific technology are
19 fundamentally flawed. No single technology should be singled out for integration
20 charges, because the system operates as a whole. Each generation technology has
21 limitations and the system should be optimized to deliver least cost service to
22 ratepayers overall rather than developing individualized charges that are only
23 applied to a subset of generation resources.

1

2 **Q: What would be necessary to rectify the issues you have identified with the**
3 **Cost of Variable Integration study DESC has presented?**

4 A: DESC should file an updated analysis as an improved starting point for
5 beginning to evaluate the interrelated issues of variable integration costs, the
6 value of solar plus batteries, and curtailment. DESC should require that their
7 consultants address the concerns presented throughout Exhibit B, implement new
8 modeling tools and updated methodologies, and adopt industry recognized
9 practices related to reserves and variable renewable integration studies. DESC
10 should also consider utilizing a Technical Review Committee (TRC), composed
11 of outside experts on variable renewable integration. TRCs have been
12 successfully used by many utilities to help guide their integration studies and to
13 utilize the latest and best integration study practices.

14

15 **Q: What is your conclusion regarding DESC's proposed variable integration**
16 **charge given the issues you have identified with the Cost of Variable**
17 **Integration study?**

18 A: The variable integration charge study has a number of problems that need
19 to be addressed. Until that happens, the study should not be relied upon to impose
20 a variable integration charge. The study and charge as proposed also indicate that
21 DESC may be seeking an approach to integrating renewables that will ultimately
22 impose unnecessary and excessive fuel and reserve costs on an ongoing basis.

23

INDUSTRY EXPERIENCE AND BEST PRACTICES

Q: Do solar variability or potential forecast errors pose reliability risks to DESC?

A: No, not at the levels evaluated by the Cost of Variable Integration report. DESC is part of a large, interconnected grid. The Eastern Interconnect spans from Maine to Florida to the Rocky Mountains. Even if all of DESC's solar generation disconnected simultaneously, there would not be a reliability risk because there is sufficient inertia and response from other generators across the region to respond. Instead, solar variability and uncertainty may pose *economic* and *coordination* challenges for DESC. Any short-term mismatch between generation and load would result in Area Control Error (which measures the unscheduled and inadvertent power flows between neighboring utilities) and a need to balance interchange with neighboring balancing authorities.

As a result, DESC should consider modifications to its coordination with neighboring balancing areas and reserve sharing groups. It is likely that neighboring utilities and balancing areas are integrating greater amounts of solar power just as DESC is. It would almost certainly be more economic for DESC and neighboring grid operators to solve those challenges collectively rather than individually.

Q: Have other grid operators successfully integrated variable renewable energy without a significant increase in reserve requirements?

There is a track record in which many grid operators performed renewable integration studies that initially estimated a need for additional operating reserves

1 to integrate more variable renewable energy. However, actual operations in many
2 places have ultimately not incorporated additional reserves despite a dramatic
3 increase in wind and solar installations.

4 For example, the Electric Reliability Council of Texas (ERCOT), which
5 operates the majority of the Texas electrical grid has actually reduced regulation
6 reserve requirements by 50% over the past several years, despite an installed
7 variable renewable energy capacity more than doubling to over 20,000 MW. In
8 addition, the California Independent System Operator (CAISO) leads the nation in
9 solar PV integration but does not carry any operating reserves to cover for the
10 variability or forecast errors of solar PV, despite over 20,000 MW of installed PV
11 capacity (12,072 MW of utility-scale PV and approximately 8,000 MW of
12 distributed behind-the-meter PV).

13
14 **Q: What mitigations have other grid operators implemented to address solar**
15 **variability and uncertainty?**

16 Other grid operators have successfully integrated variable renewable
17 energy at levels far exceeding the scenarios evaluated by DESC by implementing
18 a variety of available mitigations. For example, in 2014 CAISO implemented the
19 Western Energy Imbalance Market (EIM) to better coordinate real-time
20 interchange with neighboring balancing areas. The market ensures that the lowest-
21 cost energy is dispatched to serve real-time customer demand across a wide
22 geographic area in an effort to improve renewable energy integration. Since its
23 inception, the EIM has reduced costs by 736 million dollars. In the second

1 quarter of 2019, the EIM reduced flexibility reserves by 45% and reduced
2 renewable curtailments by 132,937 MWh.

3 Other grid operators are implementing demand response programs and
4 battery energy storage systems to provide reserves to help integrate solar energy.
5 For example, the Hawaiian Electric Company (HECO) is procuring grid services,
6 including fast frequency response, regulation reserves, and quick-start reserves,
7 through a combination of customer-sited demand response systems, standalone
8 battery energy storage systems, and hybrid solar and storage plants.

9
10 **Q: Did Dominion's Cost of Variable Integration study evaluate these other solar**
11 **integration options?**

12 No.

13
14 **RECOMMENDATIONS**

15 **Q: Please summarize your recommendations for the Commission.**

16 **A:** The Commission must consider whether any integration charges are just
17 and reasonable. Given the significant problems with the Dominion Cost of
18 Variable Integration study approach and analysis, as outlined in my testimony and
19 attached report, the Commission should not approve Dominion's proposed
20 variable integration charge. The utility should revise its approach to address the
21 problems identified and hold off on any integration charge until these concerns
22 have been addressed and the utility has gained more operational experience, so
23 that actual charges are not based solely on flawed simulations.

1

2 **Q:** **Does this conclude your testimony?**

3 **A:** Yes

Exhibit A



Derek P. Stenclik

Founding Partner

Saratoga Springs, NY

M.S. Applied Economics & Management, Cornell University

B.A. International Relations, State University of New York
at Geneseo

Derek Stenclik is a founding partner of Telos Energy and is an industry leader in power grid planning, operations, and reliability. He has nearly a decade of experience helping clients across the electric power industry navigate evolving markets, adapt to rapidly changing technologies, and accelerate clean energy integration. He is a recognized expert on deregulated power markets, wind and solar integration, battery energy storage, and distributed energy resources.

Derek combines economic and engineering principles to bring a balanced perspective towards the opportunities and challenges of our current and future energy mix. He recognizes the role of a diverse resource mix and understands the need to balance affordability, reliability, and sustainability. He provides his clients unbiased, technical, and quantitative analysis by leveraging detailed power system models and simulations.

He regularly contributes to industry forums, including IEEE, CIGRE, ESIG, and peer-reviewed publications. He has authored over a dozen peer-reviewed articles and given numerous talks related to renewable integration, low inertia power systems, energy storage, and ancillary market design.

Prior to founding Telos Energy, Derek spent eight years in GE Power's Energy Consulting department, most recently as the Senior Manager of Power System Strategy. In that role he supported global clients across the energy industry, including utilities, grid operators, developers, equity investors, and NGOs. He also provided power market expertise across GE's portfolio of businesses, including the GE Power, Renewables and Capital divisions.

Derek graduated with an M.S. degree in Applied Economics and Management from Cornell University, with a concentration in Environmental and Natural Resource Economics. He also holds a B.A. in International Relations from the State University of New York, College at Geneseo, where he graduated Phi Beta Kappa and Summa Cum Laude.

Derek P. Stenclik

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SHORT BIO

Derek Stenclik is a co-founding partner of Telos Energy and is an industry leader in power grid planning, operations, and reliability. He has nearly a decade of experience helping clients across the electric power industry navigate evolving markets and accelerate clean energy integration.

EXPERIENCE

- | | |
|--------------|---|
| 2019-Present | <p>Founding Partner, <i>Telos Energy</i></p> <ul style="list-style-type: none"> • Lead business development, marketing, and finance initiatives • Consult global clients in the electric power industry |
| 2015-2019 | <p>Senior Engagement Manager, <i>GE Energy Consulting</i></p> <ul style="list-style-type: none"> • Supported utilities, grid operators, developers, governments, and NGOs • Managed a diverse team of 11 power systems engineers and consultants • Oversaw annual sales of ~3.5M\$ |
| 2011-2015 | <p>Consultant & Senior Consultant, <i>GE Energy Consulting</i></p> |

EDUCATION

- | | |
|-----------|---|
| Aug. 2011 | <p>M.S. Applied Economics & Management, <i>Cornell University</i></p> <ul style="list-style-type: none"> • Concentration: Environmental and Natural Resource Economics • Thesis: <i>Understanding Private Forest Owner Participation in Future Carbon Offset Programs in the Catskills Region: A Contingent Valuation Approach.</i> |
| May 2009 | <p>B.A. International Relations, State University of New York at Geneseo</p> <ul style="list-style-type: none"> • Honors: Phi Beta Kappa, Summa Cum Laude |

EXPERTISE

Energy Markets and Power Systems Expertise:

- Economic dispatch and production cost modeling (GE MAPS and PLEXOS software)
- Renewable integration, integrated resource planning, and cost-benefit analysis
- Market design, energy and capacity market forecasting
- Financial proforma analysis, asset valuation, and tax equity investment
- Transmission congestion and curtailment risk analysis
- Environmental policy and regulatory analysis

AWARDS

- D. Stenclik, 2019 Excellence Award of the Electric System Integration Group (ESIG) for his work related to advances in PV-battery peaking plants.
- D. Stenclik, 2016 Annual Achievement Award of the Utility Variable-Generation Integration Group for the contribution to the Pan Canadian Wind Integration Study
- M. Richwine, D. Stenclik, 2016 Next Generation Network Paper Competition, 1st Place, CIGRE-US National Committee.

RELEVANT STUDIES

- Hawaii Solar plus Storage Integration Study, ongoing
- Hawaii Battery Energy Storage Integration Study, 2018
- Colorado Springs Utilities Solar Integration Study, 2017
- Grand Bahama Renewable Integration Study, 2017
- Saskatchewan Renewable Integration Study, 2017
- Oahu Distributed Solar Grid Stability Study, 2016
- Pan Canadian Wind Integration Study, 2016
- Barbados Wind and Solar Integration Study, 2015
- Hawaii Renewable Portfolio Standards Study, 2015
- PSEG Long Island Integrated Resource Plan, 2014
- PJM Renewable Integration Study, 2014
- Hawaii Solar Integration Study, 2013
- Nova Scotia Renewable Integration Study, 2013

PUBLICATIONS

- B. Zhang, **D. Stenclik**, W. Hall, Calculating the Capacity Value and Resource Adequacy of Energy Storage on High Solar Grids, CIGRE-US Grid of the Future, Reston, 2018.
- **D. Stenclik**, B. Zhang, R. Rocheleau, J. Cole, Energy Storage as a Peaker Replacement, IEEE Electrification, Vol. 6 No. 3, 2018.
- **D. Stenclik**, M. Richwine, C. Cox, To Shift or Not to Shift? An Energy Storage Analysis from Hawaii, Hybrid Power Systems Workshop, Tenerife, May 2018.
- **D. Stenclik**, M. Richwine, N. Miller, The Role of Fast Frequency Response in Low Inertia Power Systems, CIGRE Session, Paris, 2018.
- M. Richwine, **D. Stenclik**, Analysis and Impact of Autonomous Fast Frequency Response Relative to Synchronous Machine Sources on Oahu, CIGRE-US Grid of the Future, Reston, 2018.
- E. Ibanez, B. Daryanian, **D. Stenclik**, Capacity Value of Canadian Wind and the Effects of Decarbonization, 2017 Ninth Annual IEEE Green Technologies Conference (GreenTech), Denver, 2017.
- **D. Stenclik**, P. Denholm, B. Chalamala, Maintaining Balance: The Increasing Role of Energy Storage for Renewable Integration, IEEE Power and Energy Magazine, Volume: 15, Issue: 6, Nov. - Dec. 2017.
- G. de Mijolla, **D. Stenclik**, E. Ibanez, D. Lew, Regional Valuation of Regulating Reserves from Distributed Flexible Resources, CIGRE-US Grid of the Future, Cleveland, 2017.
- M. Richwine, **D. Stenclik**, Analysis of Grid Strength for Inverter-Based Generation Resources on Oahu, CIGRE-US Grid of the Future, Cleveland, 2017.
- M. Richwine, **D. Stenclik**, An Integrated Approach to Analyzing the Impact of Increasing Distributed PV Generation on Dynamic Stability in Oahu, CIGRE-US Grid of the Future, Philadelphia, 2016.
- D. Woodford, B. Daryanian, **D. Stenclik**, M. Salimi, The Way to a TransCanada Electric Transmission System, CIGRE Canada Conference, Vancouver, 2016.

Exhibit B

Analysis of Dominion Energy South Carolina's Proposed Variable Integration Charge

Prepared For: Southern Alliance for Clean Energy
South Carolina Coastal Conservation League

Prepared By: Derek P. Stenclik
Telos Energy, Inc.

9/23/19

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1 Introduction

This report supports the testimony of Derek P. Stenclik related to South Carolina Public Service Commission Docket No. 2019-184-E. It was prepared on behalf of South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy (SCCCL/SACE).¹ Specifically, this document reviews Dominion Energy South Carolina (DESC)'s proposed Variable Integration Charge (VIC) and the related testimony of Dr. Matthew W. Tanner. Dr. Tanner's testimony included the August 2019 Navigant report titled "Cost of Variable Integration" prepared for DESC, which is reviewed in detail throughout this report (herein referred to as the "Cost of Variable Integration study").

Variable renewable energy, namely wind and solar generation, has grown significantly in the recent decades. As the share of variable renewable energy within total generation increases, grid operations and planning should adapt to properly integrate variable generation so as to appropriately realize its benefits. Fortunately, grid planners and operators worldwide have developed years of experience to better understand the opportunities, challenges, and mitigations associated with wind and solar integration.

The basic premise that adding variable renewable generation to the power system may increase some aspects of operating costs, as stated by Dr. Tanner's testimony, is not unreasonable. The use of hourly production cost modeling to compare cases with and without additional solar generation is also generally accepted by the industry. Unfortunately, the Navigant analysis, as implemented, raises significant concerns outlined below:

The analysis overstates the level of reserve requirements needed in order to integrate renewable resources

- The modeling and planning analyses do not accurately reflect DESC's current operating practices. For instance, DESC currently does not – as reflected in Navigant's modeling – carry any operating reserves to cover for variability or forecast errors associated with the currently installed 434 MW of solar PV. If DESC has successfully integrated 434 MW of solar without additional reserves, it is unclear why DESC now proposes such high levels of reserves.
- The analysis fails to account for aggregation benefits that naturally reduce the relative forecasting errors and resource variability as the solar generation fleet grows.
- The analysis used an excessive 4-hour ahead forecast, overstating the forecast error that may impact actual operations.

¹ The analysis in this report builds on Mr. Brendan Kirby's initial review of Dominion's Variable Integration Charge and related filings. Mr. Kirby's analysis was pre-filed in South Carolina Public Service Commission Docket No. 2019-2-E but the relevant portion of that proceeding was put on hold, and is now being addressed in this proceeding, Docket No. 2019-184-E. Mr. Kirby was not available to testify in this proceeding, but I have reviewed and incorporated relevant components of his initial analysis.

- Further, the analysis fails to include off-line combined cycle (CC) generation capacity as available reserves that can mitigate 4-hour ahead solar forecast errors despite the capability of shorter start times,
- The operating reserve methodology uses an overly stringent 99% confidence interval, which overstates the required operating reserves.

The modeling methodology overstates the cost of integrating renewable resources

- Navigant assumed incorrectly that ratepayers must fund additional reserves to integrate solar resources during 8760 hours a year rather than during only the hours of forecasted solar generation, greatly overstating additional reserve costs. It is not necessary, as Dominion appears to propose, for ratepayers to fund reserves to integrate solar output during nighttime hours when solar is not operating.
- In an attempt to overcome the incorrect, self-imposed fixed annual solar reserve requirement, the study inappropriately “blended” the results from multiple production cost modeling runs with different reserve requirements. This approach does not correct the overstatement of solar reserve costs caused by holding extra solar reserves constant for 8760 hours per year, nor is it an accepted industry practice.
- The analysis failed to include significant additional reserves from the Fairfield Pumped Storage plant that are appropriately available as solar forecast error reserves.
- Neighboring power systems were not properly included in the analysis, eliminating an economic resource regularly utilized by DESC. This greatly overstates additional reserve costs.

Alternative operating reserve resources that offer potential ratepayer savings when compared to DESC's false baseline were not adequately evaluated

- Existing demand response resources were not included to the full extent possible, eliminating a valuable source of operating reserves from the analysis,
- New battery energy storage and CT units were not evaluated to include all of services they can provide, overstating the cost to implement these resources as a mitigation option,
- Alternative mitigations are available to DESC but were not evaluated. These include larger balancing area coordination, new demand response, flexible solar, existing plant upgrades, and discounting of the solar forecasts with more conservative estimates.

Variable integration charges are fundamentally flawed

- Integration charges are not appropriate unless they are assessed on all technologies. It may be more appropriate simply to recognize that each generation technology has limitations and to then optimize the power system around those limitations.

The Cost of Variable Integration study therefore incorrectly overstates the reserve requirements and associated impacts on the operating costs that DESC will likely experience as a result of increased solar generation. In order to avoid charges based on outdated and inefficient operations, DESC should update its analysis method and tools to reflect actual utility reliability requirements, capabilities, and operations. The solar data should be reanalyzed to reflect plant, forecasting, and system aggregation benefits. On the basis of this deeply flawed DESC analysis,

the Commission should reject the variable integration charges as being unjust and unreasonable.

While the proposed reserve requirements may be appropriate for long-term planning studies, basing actual variable integration charges only on modeling analyses, without supporting operational experience, is adding an expense that has not yet been incurred. As a result, it is premature to add contractual costs on long-term PPAs until more is known about the actual operational requirements needed by DESC.

The remainder of this report provides details, presents additional data and analysis, and supports the statements made above. It also provides a set of recommendations that DESC should implement in future planning studies to ensure that solar generation, operating reserves, and system flexibility is accurately modeled, and operational decisions are better informed.

2 The analysis overstates the level of reserve requirements needed in order to integrate renewable resources

The DESC proposed variable integration charge is based on the added reserves needed to compensate for errors in the 4-hour ahead solar generation forecast:

“Navigant conducted a solar uncertainty analysis, which estimated the forecast error for solar generation installed on the system. The purpose of this analysis was to determine the amount of operating reserves that must be maintained by the Company in order to ensure that DESC can reliably respond and meet system needs if actual generation is less than forecasted.”²

While solar forecast error may be a legitimate concern, the study modeled a reserve requirement that is not implemented by DESC operations, despite 434 MW of solar already operating on the system. In addition, the Study imposed excessively high reserve requirements when developing the variable integration charge because they failed to appropriately account for geographic diversity benefits as the solar generation fleet size is increased. The Study also assumed an unreasonably long 4-hour ahead solar forecast when a rolling forecast, 4-hour ahead, 2-hour ahead, and short-term forecasts, with correspondingly lower forecast error, better matches the DESC system capabilities and operations.

2.1 Modeling analysis does not accurately capture current operating practices

With any modeling or reserve analysis, it is important that the inputs and assumptions for the production cost model match actual operating practices as close as possible. This ensures that the commitment and dispatch decisions that are simulated in the production cost model are as close as possible to the ones that will be made when operating the grid. Because the variable integration analysis was focused on the costs of providing reserves, it is essential that the model accurately reflects current operating reserve requirements.

² Direct Testimony of Matthew W. Tanner, Ph.D., Docket No. 2019-184-E, p. 7.

Unfortunately, the operating reserve assumptions made in the *Cost of Variable Integration* study do not reflect current operations. Therefore, the resulting cost of the reserves likely will not align to actual costs incurred in operations. According to the *Cost of Variable Integration* report,

“DESC is required to hold 200 MW of reserves at all times to meet their requirements within VACAR to be able to respond to the loss of the single-largest unit on the system. An additional 40 MW of reserves are held for load-following. ... However, DESC must also ensure that sufficient system reserves are available to replace generation when the actual solar generation is below the forecast. This would result in holding additional reserves on top of the 240 MW already required.”³

In “Table 12, Maximum Additional Reserves Needed,” the reserve requirements are listed as 240 MW in the “Business as Usual (BAU)” case and are increased to 348 MW in 2020 for the “Initial Solar Case.” This represents an increase of 108 MW of reserves every hour of the year with 336 MW of installed solar capacity evaluated in the Initial Solar Case. According to DESC, “the base case and first tranche contains 336 MW of solar 22 generation actually under construction and expected to be interconnected with 23 DESC’s system by the end of 2018.”⁴

There are two discrepancies between the production cost modeling and actual operations. First, actual PV installations were higher than expected by the end of 2018. “The cumulative nameplate facility rating of 7 utility scale solar generation actually interconnected with the Company’s system by the end of 2018 was approximately 310 MW. The total solar installed was approximately 434 MW as compared to the Navigant Baseline scenario of 336 MW.”⁵

Second, DESC currently does not carry any operating reserves to balance variability or forecast errors for installed PV on their system. DESC has described their operating reserve practices as follows,

“DESC must currently maintain 195 MW of contingency reserves under the VACAR reserve sharing agreement. At least one half of the requirement must be maintained in spinning reserves. Up to one half of the requirement may be interruptible load and counted as non-spinning reserves. This contingency reserve number changes from year to year depending on DESC’s share of VACAR load and the single largest contingency on the system. The Study assumption was to set it to 200 MW.

³ Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), *Cost of Variable Integration*, Navigant Consulting, August 2019, pp. 8, 10.

⁴ Direct Testimony of Eric H. Bell, Docket No. 2019-184-E, p. 20.

⁵ Direct Testimony of Eric H. Bell, Docket No. 2019-184-E, p. 21.

Additionally, DESC maintains 40 MW of other operating reserves for dynamic load following. This was added to the 200 MW and resulted in the total of 240 MW of operating reserves as business-as-usual.”⁶

Comparing the production cost modeling assumptions and actual operating reserves carried by DESC highlights an important discrepancy. **DESC currently does not carry any operating reserves, either spinning on non-spinning, to cover for variability or forecast errors associated with the currently installed 434 MW of solar PV.** Despite this, DESC has not had system-level outages and 2018 Area Control Error (ACE), which quantifies the amount of unscheduled and inadvertent flows of electricity between interconnected utilities, was below 2016 and 2017 levels. The Navigant study however does include reserves of 108 MW in the Initial Solar Case that are not currently held by DESC. This inflates the overall reserve requirement and the associated costs. When asked to confirm the potential discrepancy, DESC stated “There is not discrepancy. The study considers solar penetration scenarios and reserve requirement cases.”⁷

Many renewable integration studies that evaluate system operations with increased penetration of variable renewable energy estimated some level of additional operating reserves. However, actual operations in many places have not incorporated additional reserves despite a dramatic increase in wind and solar installations.

For example, the Electric Reliability Council of Texas (ERCOT), which operates most of the Texas electrical grid has actually *reduced* regulation reserve requirements by 50% over the past several years, despite an installed variable renewable energy capacity more than doubling to over 20,000 MW.⁸

⁶ Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request 3-1, Docket No. 2019-2-E.

⁷ Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request 3-1, Docket No. 2019-2-E.

⁸ Lew, et al., *Secrets of Successful Integration, Operating Experience with High Levels of Variable, Inverter-Based Generation*. IEEE Power & Energy Magazine, November/December 2019 (forthcoming).

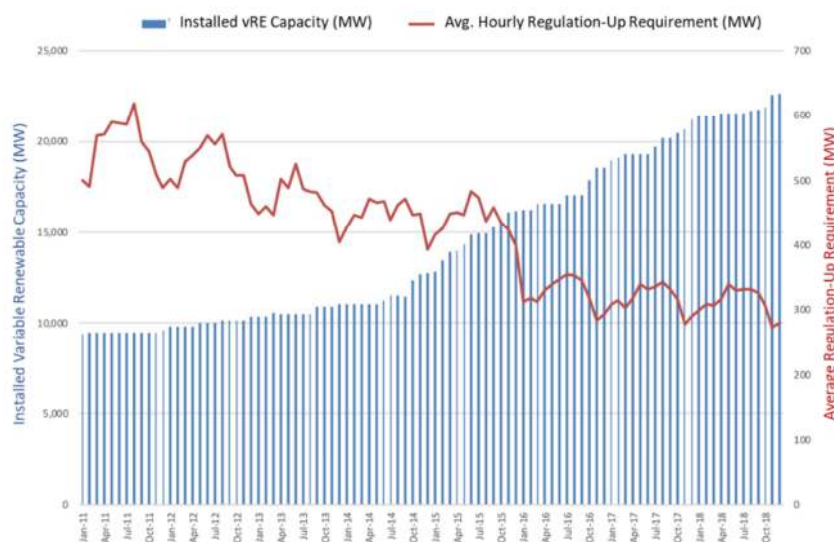


Figure 1: ERCOT Historical Variable Renewable Capacity and Average Regulation Reserves

In addition, the California Independent System Operator (CAISO) leads the nation in solar PV integration but has not increased regulation requirements (regularly between 300 and 400 MW), despite over 20,000 MW of installed PV capacity (12,072 MW of utility-scale PV and approximately 8,000 MW of distributed behind-the-meter PV).⁹

In the past, CAISO implemented increased regulation requirements for solar PV integration, but reversed that decision over time. Currently regulation requirements are at or below historical levels, despite continued growth in solar resources. A timeline of this progression is provided below:

“Regulation requirements were relatively constant for many years prior to 2016. However, between February and June [2016] the ISO roughly doubled the regulation requirements to manage increased variability of renewable resources. During these months, regulation costs were about six times higher than the same months in 2015. In June [2016], the ISO set regulation requirements back to prior levels. In October the ISO introduced a new methodology for calculating requirements on an hourly basis. After this modification, regulation costs were about 80 percent higher than the same period in 2015.”¹⁰

“On June 14 [2017], the ISO began increasing operating reserve requirements during midday hours to account for solar generation in the system by using an existing functionality within the software that allows operators to increase the

⁹ See California ISO, What are we doing to green the grid? (Sept. 20, 2019) <http://www.caiso.com/informed/Pages/CleanGrid/default.aspx>. The data on behind-the-meter solar is from Energy Solutions, California Distributed Generation Statistics (last accessed Sept. 20, 2019) <https://www.californiadgstats.ca.gov/>.

¹⁰ Dep’t. of Market Monitoring, California ISO, CAISO 2016 Annual Report on Market Issues and Performance (May 2017), available at <http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf>.

requirement by a specified percent of the load forecast. Starting on September 19, the upward adjustments were removed. Average day-ahead requirements for regulation up and down decreased by about 22 percent and 14 percent from 2016, respectively.”¹¹

Over time CAISO operators have gained valuable experience integrating solar PV, incorporating improved forecasting, and increasing coordination with neighboring systems. This has allowed them to maintain or reduce regulation requirements despite continued solar PV growth. Currently they hold approximately 350 MW of regulation reserves with over 20,000 MW of installed solar PV capacity. That’s roughly the same amount of reserves considered by DESC to integrate only 1,112 MW of solar PV.

While many variable integration studies include a reserve requirement specifically for variable renewable generation, actual operational practice at DESC and other grid operators with high levels renewable integration suggest otherwise. Actual operations may not require as high of a reserve requirement as indicated by the integration analyses. While these reserve requirements may be appropriate for long-term planning studies, basing actual variable integration charges only on modeling analyses, without supporting operational experience, is adding an expense that has not yet been incurred. As a result, it is premature to add contractual costs on long-term PPAs until more is known about the actual operational requirements needed by DESC.

Recommendation: The Commission should direct DESC to not include the additional 108 MW of reserves in the Initial Solar Scenario that are currently not reflective of actual operating practices. In addition, the Commission should consider delaying the implementation of any variable integration charge until more is understood about the effect on actual system operations. At a minimum, the Commission should consider making any implementation of variable integration charges a temporary measure until more detailed analyses can be performed based on actual operating practices.

2.2 Analysis failed to fully account for aggregation benefits of solar

In order to quantify solar forecast error, Navigant used a year of 5-minute solar data supplied by the National Renewable Energy Laboratory (NREL) from four sites in the DESC service territory. The NREL data also includes a simulated 4-hour ahead hourly forecast for each site. The Cost of Variable Integration report explained that:

“[a]veraging the forecast error among multiple locations properly accounts for the expected geographic diversity of solar resources being added to the system. This ensures that the analysis is not too aggressive in estimating the additional reserves needed by DESC.”¹²

¹¹ Dep’t. of Market Monitoring – California ISO, CAISO 2017 Annual Report on Market Issues and Performance (June 2018), available at <http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf>.

¹² Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), *Cost of Variable Integration*, Navigant Consulting, August 2019, p. 23.

The study is correct that averaging the forecasts from multiple sites reduces the forecast error. However, the study only used data from four points around DESC's territory. By limiting the analysis to four sites, the study unduly limits the forecast error benefits of more geographically dispersed solar. In other words, the forecast error would be further reduced when more solar generators are added to the aggregation.

There is no reason to assume that forecast aggregation benefits stop with a four-solar-plant aggregation. Additional smoothing is likely and forecast errors would be reduced much more than the 24% reduction seen when averaging across only four sites. As the solar fleet increases to over 1,000 MW it will be composed of dozens of utility-scale solar projects located across the state, along with tens to thousands of rooftop PV systems spread over the entire DESC service territory and facing different directions. Aggregation benefits will significantly reduce short-term forecast errors as well as short-term solar output volatility. In turn, this will significantly reduce the required operating reserves and associated costs. The study should account for these additional benefits of geographic diversity as the solar fleet grows.

Solar generation variability itself is also significantly overstated in the Cost of Variable Integration analysis. This impacts the cost of production as conventional generators must respond to greater-than-actual hour-to-hour changes in aggregate solar output. Actual solar variability declines significantly with aggregation but DESC confirmed that "[t]he 8760 shapes used in the analysis were linearly scaled with total installed solar MW nameplate."¹³

The Cost of Variable Integration report states that "[t]he hourly shape for solar generation that is inputted into PROMOD is developed from an aggregation of real solar generation hourly shapes from DESC."¹⁴ DESC stated that "[t]he data was actual hourly operating data for 7 projects installed on the DESC system."¹⁵ These seven projects had a nameplate capacity of 46.68 MW. Analysis of the year of data shows that average hour-to-hour variability for the aggregation was 51% less than the average hour-to-hour variability of the individual plants. That is, increasing the solar fleet size by a factor of seven cut the hour-to-hour variability in half. Increasing the solar fleet size by another factor of 22, to the level of ~1050 MW evaluated in the Study, will again significantly reduce the hour-to-hour solar variability.

The 2030 hourly production cost modeling for the All Solar Case includes 40 named solar plants, but the output from many of the plants is perfectly correlated with the output from other plants. For example, the hourly outputs for Barnwell Solar Farm, Estill Solar I Project, Estill Solar

¹³ Response to South Carolina Conservation League and Southern Alliance for Clean Energy First Data Request 1-10, Docket No. 2019-184-E (confirming that the response to this request remains the same as the one previously provided to SACE and CCL in Response 11 of SACE and CCL's Third Data Request, Docket No. 2019-2-E); South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request 1-11, Docket No. 2019-2-E.

¹⁴ Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), *Cost of Variable Integration*, Navigant Consulting, August 2019.

¹⁵ Response to South Carolina Conservation League and Southern Alliance for Clean Energy First Data Request 1-11, Docket No. 2019-184-E (confirming that the response to this request remains the same as the one previously provided to SACE and CCL in Response 3-12 of SACE and CCL's Third Data Request, Docket No. 2019-2-E); Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request 3-12, Docket No. 2019-2-E.

II LLC, Haley (Allendale) Solar Farm, Hampton Solar 1, and Hampton Solar 2 are all perfectly correlated. These do not represent six separate solar plants but are six copies of the same facility. There are only 19 independent entities in the PROMOD analysis. Each of these may still overstate variability since the output of a single larger plant is inherently less variable (on a percent of name plate basis) than the output of a smaller solar plant because of the necessarily larger physical size of the larger solar plant.

Recommendation: The Commission should direct DESC to analyze solar output and forecast data from a realistic representation of geographically diverse and realistically sized solar plants for the high penetration solar cases. The current interconnection queue can be used as a guide for potential solar siting.

2.3 The 4-Hour ahead forecast is excessively long

Solar forecast error naturally declines closer to the operating hour. The least reserves are required, and the lowest costs will be incurred, if the most accurate, and therefore shortest-term forecast, is used. A forecast generated just before a system operator needs to decide whether to take action (starting an additional CC unit to supply additional reserves, for example) will result in the least required reserves and the lowest added cost. The 4-hour window does not represent state-of-the-art forecasting capability, commercial service offerings, or technical constraints of the DESC fossil generation, but rather the available data in the NREL datasets. In actual operations, the utility can implement a rolling solar forecast that is routinely updated at day-ahead, 4-hour ahead, 2-hour ahead, and real-time intervals. This will allow for rolling decisions that occur throughout the day, rather than at static pre-determined intervals.

Navigant's Cost of Variable Integration study used the readily available NREL 4-hour ahead solar forecast that is coupled with the NREL 5-minute solar data. Navigant makes the following claim that the use of a 4-hour ahead solar forecast is justified:

"This is appropriate because as the solar generation changes in the period between the 4-hour ahead forecast and actual operation, DESC will not have sufficient time to turn on any additional CC or ST units. The only reserves that are available are the additional generating capacity, or headroom, for Fairfield, Saluda, the CTs, and the CCs and STs that are already online."¹⁶

When asked why a 2-hour ahead forecast was not used, since many of the DESC CC units and most of the CT units can start in under 2 hours, DESC stated:

"The 4-hour forecast is an appropriate estimate for the forecast error because, although some of the CCs can start in 2 hours, there would need to be some lead time between receiving the forecast and discovering that it is less than the expected solar generation. This assumption is that DESC would not be able to know whether the forecast was wrong for at least two hours after receiving the four-hour ahead forecast. This analysis is conservative in that many of the ST

¹⁶ Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), *Cost of Variable Integration*, Navigant Consulting, August 2019, p. 21.

*plants on the system and a few of the CCs need longer than 2-4 hours to start.*¹⁷
(emphasis added)

This response misrepresents the objective of operating reserves. Variable integration reserves are designed to protect against the *possibility* that the solar forecast is so wrong that there won't be enough reserves to cover any drop in actual solar generation. The operator does not need to determine if the current forecast is accurate; the reserves are being held precisely in case the forecast is wrong. If there is time to determine if the forecast is correct, then there is no need for forecast-error reserves. With a 2-hour ahead forecast there is no need to wait and determine if the solar forecast is accurate. The reserve requirement is based on the forecast amount and already incorporates the risk that the forecast is wrong. If the 2-hour ahead forecast estimates a solar generation level that indicates the need for an additional CC to be operating to supply reserves, the CC can begin to be started immediately.

The Cost of Variable Integration study also did not allow off-line CC plants to provide any reserves. As DESC states, with a 4-hour ahead forecast there is ample time to start an off-line CC after determining that the 4-hour ahead forecast is in error.

Recommendation: The Commission should direct DESC to augment its 4-hour ahead forecast interval to also include one or two hours, with an equivalent reduction in estimated forecast error. Alternatively, off-line CCs should be allowed to provide at least a portion of reserves.

2.4 The operating reserve methodology used an overly stringent 99% confidence interval

When determining the operating reserve requirement, it is important to note that the reserves do not cover 100% of all possible drops in solar generation. Instead, the reserves cover a confidence interval that cover for the vast majority, but not all, drops in solar generation. This ensures that reserves are not held for extreme outlier events that may be very rare and/or an artifact of bad data.

In the Navigant Variable Integration Cost study, "[t]he analysis used 1% as the threshold for calculating the risk of solar generation being less than expected. The most extreme outliers were excluded from the analysis."¹⁸ While the implementation of a confidence interval is a generally accepted practice in the industry, the selection of 99% (meaning the reserves cover for 99% of all solar drops) is overly stringent and higher than typical confidence intervals used in other variable integration studies. Further, it does not appear that the selection of the 99% confidence interval was based on actual analysis, but rather an arbitrary assumption.

¹⁷ Response to South Carolina Conservation League and Southern Alliance for Clean Energy First Data Request 1-13, Docket No. 2019-184-E (confirming that the response to this request remains the same as the one previously provided to SACE and CCL in Response 3-14 of SACE and CCL's Third Data Request, Docket No. 2019-2-E); Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request 3-14, Docket No. 2019-2-E.

¹⁸ Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), *Cost of Variable Integration*, Navigant Consulting, August 2019, p. 18.

For example, the National Renewable Energy Laboratory's (NREL) *Eastern Renewable Generation Integration Study* (ERGIS),¹⁹ used "confidence intervals that covered 95% of the forecast errors. These requirements approximate levels of coverage used in past integration studies. The 95% confidence interval is also supported by Ibanez, et al., "The regulation reserves were calculated using 10-min time and 95% confidence intervals for the entire footprint. The results are represented in Fig. 6. Flexibility reserves were calculated for different subregions using hourly time steps and 70% confidence intervals."²⁰

Decreasing the confidence interval slightly, for example from 99% to 95% could result in a significant reduction in the reserve requirement and associated costs and only result in a very few number of hours across an entire year where there is a small risk that there would be a drop in solar beyond the reserve requirement. This would not jeopardize system reliability. Very rare events are not a reliability concern, but rather a potential low probability reserve violation. If an event were to occur during this time, it would be mitigated quickly by increasing the DESC's imports (or reducing exports) and increase DEC's Area Control Error (ACE) slightly. In addition, there would still be sufficient contingency reserves held on the system that could be used if necessary.

In actual operations, perfect balance of DESC's load and generation is not expected or required. In fact, reliability standards are designed *assuming* some level of acceptable imbalance. The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. Part of NERC's missions is to develop and enforce Reliability Standards. For example, *NERC Standard BAL-001-2 – Real Power Balancing Control Performance* is designed to manage balancing requirements for each balancing authority in North America, with the objective of controlling interconnection frequency within defined limits.²¹ According to NERC BAL-001-2, a balancing area has 30-minutes to correct for any imbalance before there is a violation.

Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates.

Therefore, it is not expected that DESC cover for 100% or even 99% of all solar drops on their system. In the event of a large solar drop that exceeds the reserve requirement, DESC will temporarily import (or decrease exports) from neighboring systems. This occurs automatically,

¹⁹ Bloom, et al., *Eastern Renewable Generation Integration Study*, National Renewable Energy Laboratory, August 2016, available at <https://www.nrel.gov/grid/ergis.html>.

²⁰ Ibanez, et al., *A Solar Reserve Methodology for Renewable Energy Integration Studies Based on Sub-Hourly Variability Analysis*, National Renewable Energy Laboratory, November 2012, available at <https://www.nrel.gov/docs/fy12osti/56169.pdf>.

²¹ NERC, *Reliability Standards for the Bulk Electric Systems of North America*, Updated June 5, 2019, available at <https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf>.

as power flows across the grid faster than a utility can balance the grid. That is why NERC standards allows for some degree of inadvertent and unscheduled flows. This would only increase ACE slightly until DESC could rebalance. Below is a chart of 2018 10-minute ACE values for DESC (formerly DESC),²² showing that imbalances often exceed 100 MW.

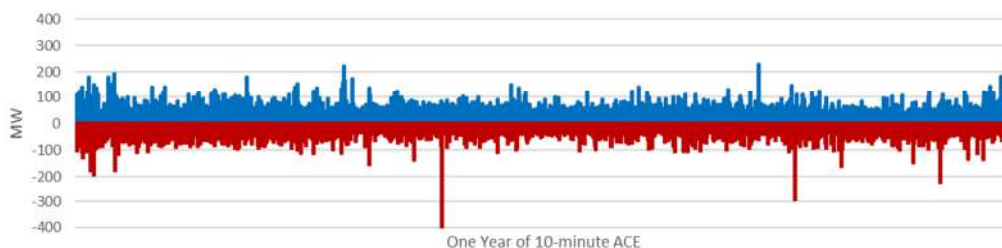


Figure 2: 2018 DESC 10-Minute ACE Data

Recommendation: The Commission should direct DESC to utilize a more appropriate 95% confidence interval for the solar operating reserve requirements when calculating variable integration costs.

3 The modeling methodology overstates the cost of integrating renewable resources

While the *Cost of Variable Integration* analysis generally implements industry accepted methods, there are several limitations introduced either by limitations in the modeling tool implemented (PROMOD) or simplified assumptions made with the input data. As a result, there are five modeling methodology concerns outlined below the limit the accuracy and applicability of the Study results.

3.1 Additional reserve requirements were imposed 8760 hours per year

The *Cost of Variable Integration* report notes “[t]he operating reserve requirements from solar are driven by the level of forecast uncertainty in the solar generation. The NREL dataset provides the 4 hour-ahead forecast of hourly solar generation. This is the forecast that DESC system operators would use to schedule their units and determine which generators are required to be online.”²³ The production cost modeling, however, did not adjust the solar forecast reserve requirements hourly based on the forecasted solar generation. Instead, DESC explained that “[d]ue to PROMOD’s structure, the reserve requirements were increased in all hours.”²⁴ That is, fixed reserve requirements were imposed in all 8760 hours of each year and

²² Historical ACE data available online. See Dominion Energy South Carolina OASIS (last updated Aug. 14, 2019) <http://www.oatiaoasis.com/sceg/index.html>.

²³ Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), *Cost of Variable Integration*, Navigant Consulting, August 2019, p. 18.

²⁴ Response to South Carolina Conservation League and Southern Alliance for Clean Energy First Data Request 1-17, Docket No. 2019-184-E (confirming that the response to this request remains the same as the one previously provided to SACE and CCL in Response 3-18 of SACE and CCL’s Third Data Request, Docket No. 2019-2-E); Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request 3-18, Docket No. 2019-2-E.

reserves were not adjusted based on expected solar generation, as would be done in actual operations, simply because of a modeling limitation. DESC therefore proposes to penalize solar generators based on an analysis that imposed high reserve requirements far in excess of the amount of solar generation online during most hours of the year. This is not an accepted industry practice and results in calculation of unreasonably high production cost.

It should be noted that alternative production cost modeling tools that are commercially available, such as GE MAPS, PLEXOS, and SERVUM, which allow for hourly reserve requirements to more accurately account for solar variability and uncertainty. These tools are regularly implemented across the industry for wind and solar integration studies.

DESC attempts to justify the analysis method by stating that “There are a limited number of hours in which the reserve requirements are a binding constraint that forces system operation to change and these hours are generally in the middle of the day when solar is on line.”²⁵ (emphasis added).

However, Figure 9 of the Cost of Variable Integration report shows a frequency distribution of reserve shortfall by hour of the day. This chart represents the inadequacy of a static reserve requirement. From 5PM to 7PM when the reserves are most binding and costly, solar output is significantly lower (or zero during the winter months) than the middle of the day so less reserves need to be carried. The evening solar down ramp is not uncertain and can be forecasted with a high degree of accuracy.

In addition, the Study states that “these hours are concentrated during the evening when solar is ramping down.” This statement is misleading as it is likely that the dominant reason for reserve shortfalls is due to increasing system load and the chart would have a similar shape in the absence of solar resources on the system. There are also a handful of reserve shortfalls during the overnight periods (8PM to 11PM) which definitively are *not* caused by forecast errors or variability in solar generation.

Recommendation: The Commission should direct DESC to accurately model actual hourly reserve requirements using appropriate and capable modeling tools.

3.2 Blending of production cost modeling results is not an appropriate solution

As indicated in the following description, Navigant recognized that imposing a fixed solar reserve requirement 8760 hours a year is not appropriate and they therefore developed a technique to try to correct this deficiency:

“Because the solar forecast is not the same each day, Navigant then blended the results of the PROMOD® runs with the different levels of reserves to account for days in which less solar is forecasted than others. For example, the analysis calculated integration costs for the

²⁵ Response to South Carolina Conservation League and Southern Alliance for Clean Energy First Data Request 1-17, Docket No. 2019-184-E (confirming that the response to this request remains the same as the one previously provided to SACE and CCL in Response 3-18 of SACE and CCL’s Third Data Request, Docket No. 2019-2-E); Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request 3-18, Docket No. 2019-2-E.

All Solar Case using the following proportions of days in which these levels of reserves must be maintained:

- *All Solar level of reserves is needed 38% of the days*
- *Intermediate level of reserves is needed 51% of the days*
- *Initial Solar level of reserves is needed 12% of the days*²⁶

*"If the maximum operating reserve increases were assumed to be maintained every day, the estimate of integration costs would be too high. PROMOD does not allow operating reserve levels to change day-to-day. Therefore, in order to incorporate the days with lower requirements, Navigant calculated the costs using varying levels of operating reserves and then blended those costs using weightings tied to the proportion of days with the appropriate level of solar uncertainty."*²⁷

Further, the *Cost of Variable Integration* report itself states:

*"An outcome of the solar uncertainty analysis, described in more detail in Section 3, is that the level of solar generation uncertainty depends on the level of solar generation. The amount of reserves that need to be held by DESC for variable integration depend on the level of forecasted solar generation. This dynamic is incorporated into the study analysis by blending the production costs of several cases operating the system with different levels of operating reserves to account for the day-to-day variability in the overall requirements."*²⁸

*"To ensure that the analysis does not overestimate the costs to integrate the All Solar reserves, PROMOD was run with each of these levels of reserves and then the results were blended using the weighted average of costs tied to the number of days that each level of reserves was required."*²⁹

This approach of "blending" results from production cost modeling runs with different reserve requirements does not follow industry norms and does not fix the problem. If high costs result from modeling excessive reserve requirements in hours when solar generation is not producing, then those costs are not real, and it does little good to "blend" them based on the number of hours solar generation was producing. For one, the solar reserves do not just vary from day-to-day as the "blending" implies, but rather hour-to-hour. In the simplistic example given above it would not be appropriate to say that the 300 MW added conventional generation capacity requirement should be reduced to 150 MW because it was only calculated in one of the two cases. In that example, the higher cost was a complete artifact of the flawed modeling of the reserve requirement and it should be eliminated, not "blended."

²⁶ Direct Testimony of Matthew W. Tanner, Ph.D., Docket No. 2019-184-E, p. 18.

²⁷ Direct Testimony of Matthew W. Tanner, Ph.D., Docket No. 2019-184-E, pp. 19-20.

²⁸ Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), *Cost of Variable Integration*, Navigant Consulting, August 2019, p. 18.

²⁹ Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), *Cost of Variable Integration*, Navigant Consulting, August 2019, p. 27.

Recommendation: The Commission should direct DESC to accurately model actual hourly reserve requirements. If the modeling tools or techniques are not adequate to represent actual conditions and requirements, DESC should fix or replace them.

3.3 The Fairfield pumped storage plant was not properly modeled

Based on the year of hourly PROMOD All Solar case results for 2030, the Fairfield Pumped Storage Hydro (PSH) plant is only credited with supplying reserves when it is already on-line and generating. The reserve amount is then the difference between the 576 MW plant generating capacity and the current generation level (further limited by the current reservoir level). In the 2030 All Solar case, this was an impressive 308 MW reserve average for 1336 hours.

Fairfield has additional reserve capability that could be used for integrating solar generation. The Fairfield Pumped Storage plant can switch from pumping to generating in less than 15 minutes.³⁰ That is too slow to allow Fairfield to be counted as a non-spinning contingency reserve, but it is much faster than necessary for reserves to cover errors in solar forecasts.

The 2030 All Solar PROMOD case results show the Fairfield reservoir level above 576 MWh (1 hour of generation at full output) for 7593 hours. That would allow an additional 6223 hours per year of 576 MW reserve supply in addition to the 1336 hours that is already credited for on-line generation reserves. The Fairfield reservoir could also provide partial reserve capability when the reservoir is below 576 MWh.

In addition, pumped storage technology is especially flexible because it can act as both an electrical load (when pumping) and a generator. If the plant is pumping when there is a drop in solar generation it can stop pumping and effectively reduce system load. This is a valuable form of “demand response” and an effective load reserve that should be counted. As discussed above, the plant can switch from pumping mode to generation mode in less than 15 minutes. The reserves when pumping can there be 200% of the nameplate capacity because it can stop pumping (effectively reducing system load), and then add generation. The max reserve capability is therefore 1,240 MW, much higher than the 576 MW assumed by Navigant.

When this flexibility is accurately considered, the total reserves available from Fairfield PSH increases from 412 GWh in the Navigant analysis (47 MW on average), to 4,763 GWh (544 MW on average). The Fairfield PSH plant could therefore provide 83% of the total reserves required by the Navigant study. The daytime portion of the remaining reserve requirement equates to approximately 52 MW on average, which could be more than accounted for by the 100 MW of available interruptible load. Figure 3 provides a comparison of the Fairfield Pumped Storage reserve capability in the Navigant PROMOD simulations versus calculations that fully account for the plant's flexibility.

³⁰ Response to South Carolina Conservation League and Southern Alliance for Clean Energy First Data Request 1-4, Docket No. 2019-184-E (confirming that the response to this request remains the same as the one previously provided to SACE and CCL in Response 3-4 of SACE and CCL's Third Data Request, Docket No. 2019-2-E); Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request 3-4, Docket No. 2019-2-E.

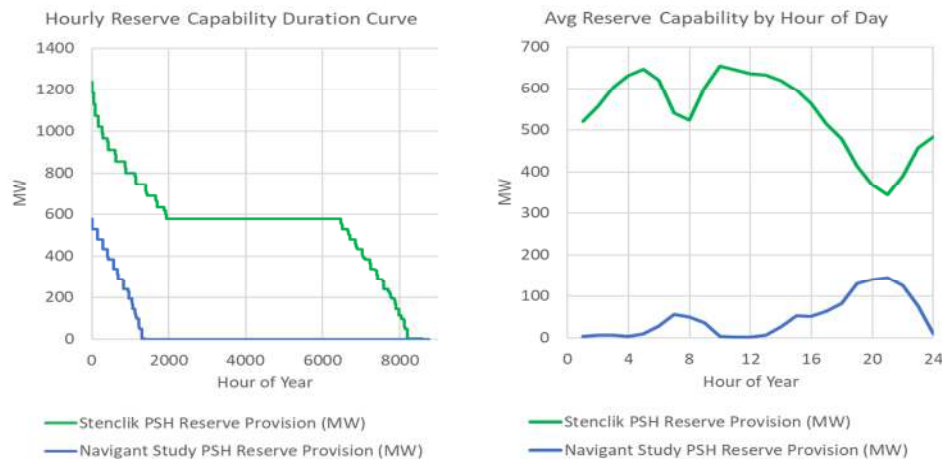


Figure 3: Fairfield Pumped Storage Reserve Capability

Finally, PROMOD hourly generation and pump load results for the Fairfield pumped storage highlight the need for co-optimization of energy and reserve requirements. The chronological hourly profile shows the plants reservoir as empty (2 MWh or less) for 405 hours of the year. If a nominal amount of energy was maintained in the reservoir the plant could provide operating reserves for the entire year and only “give up” a small amount of energy benefits. This would represent a relatively small opportunity cost to capture a relatively large reserve benefit.

It is important to note that the increased reserve capability for the Fairfield PSH plant would not require the plant to regularly switch operating modes (from pumping to generating), but rather be prepared to switch operating modes in the event of an unlikely, but possible, large solar forecast error. It is not expected that using the Fairfield PSH plant for solar reserves would have a significant negative effect on the plant’s equipment.

Recommendation: The Commission should direct DESC to count Fairfield generation as available reserve for integrating solar generation whenever Fairfield is off-line or pumping and there is sufficient storage available. In addition, the Fairfield pumping load should be counted as available reserves for integrating solar generation. If the PROMOD tool cannot adequately model the PSH flexibility, a new tool should be utilized for the analysis. The analysis should also consider scheduling a minimum energy reserve and not a full depletion of storage to understand the benefit-cost of this operating strategy.

3.4 Neighboring power systems were not evaluated correctly

Another modeling methodology concern in the Navigant *Cost of Variable Integration* report is the lack of modeling for neighboring power grids and utilities. According to the report,

“Due to the need for self-sufficiency, DESC must rely on its own generators to meet generation and reserves and cannot rely on external sources.” (page 8)

“In this study, DESC is modeled as a mostly isolated system without dynamic transmission connections to surrounding systems. This is appropriate for a planning study as it captures the requirement for DESC to maintain self-

sufficiency in planning. As DESC does have the ability to contract for external power, emergency power imports were allowed at a cost of \$300/MWh.”³¹

These statements and the underlying assumptions do not reflect DESC's actual operations and physical characteristics of the power grid. They also have the likely impact of significantly skewing the results of the study and leading to over-stated variable integration charges. Simulating DESC as an “electrical island” is not based on economic or engineering principles.

DESC is not an island, either geographically or electrically speaking. Instead, DESC is part of a much larger electrical grid that spans the entire Eastern Interconnection of North America. Power can, and regularly does, flow from one region to another. There are both economic transfers and inadvertent flows of electricity from one utility to another on a regular basis.

Figure 2, references previously, illustrates the amount of inadvertent flows (measured as area control error) between DESC and neighboring utilities. More importantly for the production cost analysis, there are additional economic imports and exports between DESC and neighboring utilities, highlighting the fact that DESC does not always need to be self-sufficient and modeling such a requirement is inaccurate and likely results in overestimating solar integration costs.

Based on data from EIA,³² DESC regularly imports and exports power from its neighbors. This is illustrated in the charts below, which provide net interchange between DESC and each of the neighboring balancing areas. This data is illustrated in Figure 4, which shows one year of hourly imports and export GWh and count of hours between DESC and neighboring balancing authorities.

³¹ Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), *Cost of Variable Integration*, Navigant Consulting, August 2019, p. 18.

³² See U.S. Energy Information Administration, Open Data (last accessed Sept. 20, 2019) <https://www.eia.gov/opendata/qb.php?category=2122610>.

Analysis of Dominion Energy South Carolina's Proposed Variable Integration Charge

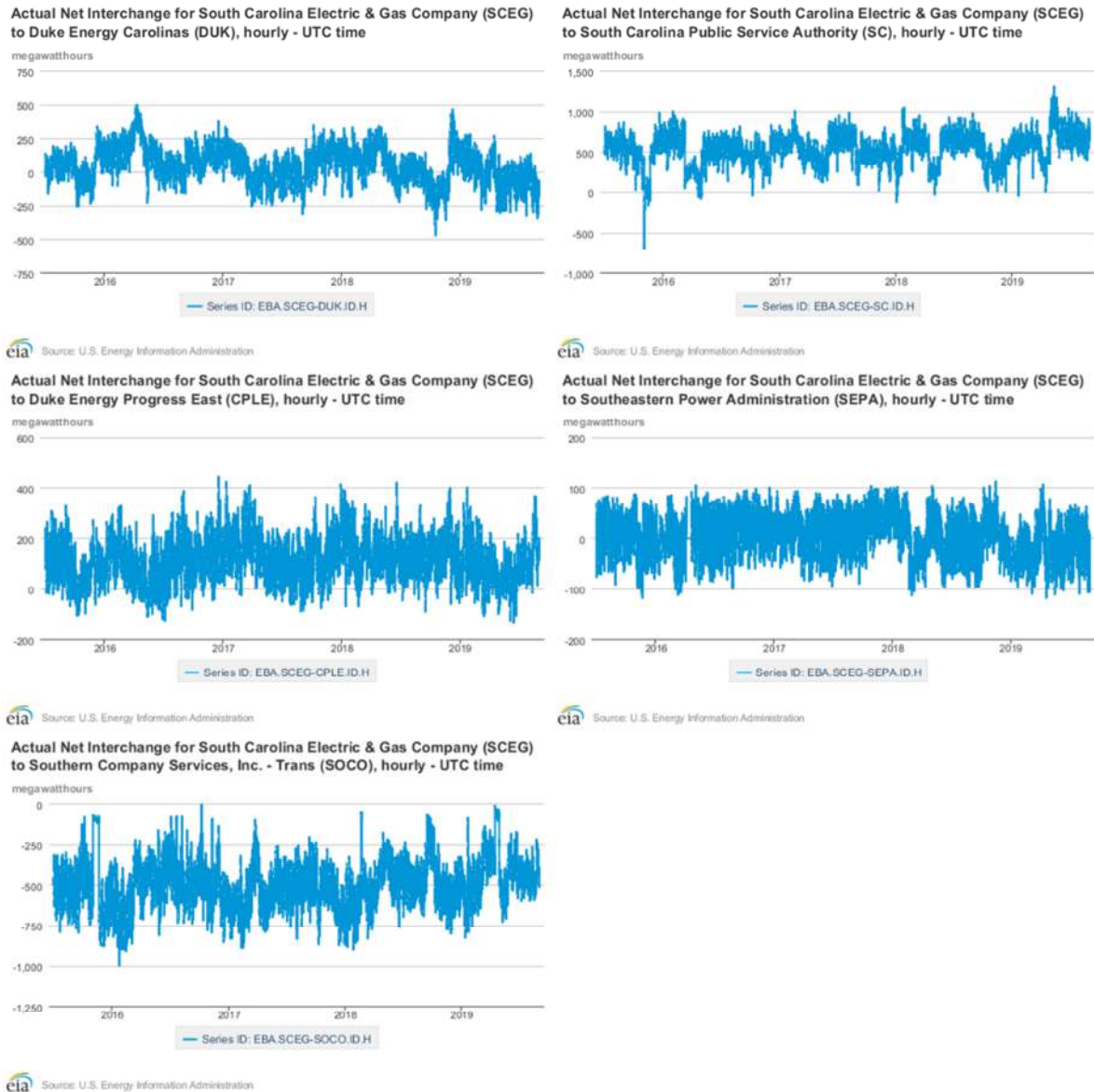


Figure 4: Hourly Net Interchange for DESC to Neighboring Balancing Authorities 2018 – 2019

When asked if DESC operates as an isolated system, as suggested in the Navigant report, DESC recognized that DESC does not fully operate as an isolated system,

*“DESC is interconnected with Duke Energy Carolinas, Duke Energy Progress, Santee Cooper and Southern Company, and **does not fully operate as an isolated system**. There is limited short-term interface, and spot market power prices have been higher than the system avoided cost. This has resulted in limited market interaction in recent years.*

For a reliability planning study such as the Variable Integration Cost study, it is not appropriate to assume that market transactions will be available to support solar integration. Other connecting utilities may be facing the same challenges at the same time. Therefore, the appropriate assumption for such a study is to model the system as mostly isolated.”³³ (emphasis added)

When asked about the frequency of energy or capacity transactions with neighboring entities, DESC replied, “During the Review Period (calendar year 2018), DESC engaged in 446 energy or capacity transactions.”

The data presented in this section clearly indicates that DESC routinely utilized interchanges between neighboring balancing areas both for economic and reliability needs. Ignoring these interchanges and modeling DESC as an isolated grid is therefore not an accurate representation of economic or physical reality. These interchanges allow for imports during some, if not all, reserve shortage events that could occur due to solar variability and forecast errors. The lack of simulated interchange with neighboring utilities likely artificially, and substantially, increased the integration costs developed by the Navigant study.

In addition, DESC's assertion that the isolated modeling was appropriate because “other connecting utilities may be facing the same challenges at the same time” is unfounded. For one, this assertion ignores the geographic diversity principles previously discussed, as it is highly unlikely (if not impossible) that solar generation rapidly and unexpectedly drops off simultaneously across the entire Southeastern US. Second, allowing for interchange between neighboring systems also increases the amount of reserve supply, diversifying the number and type of resources that are available to respond to a drop in solar output.

DESC's assertion that spot market power prices have been higher than system avoided cost may have been true over the recent past. However, future pricing may be substantially different due to solar integration in DESC's service territory and in neighboring balancing authorities. In addition, the spot market power prices are likely much lower than the marginal cost of electricity and reserves during shortage events reported in the Navigant study. It is likely that

³³ Response to South Carolina Conservation League and Southern Alliance for Clean Energy First Data Request 1-5, Docket No. 2019-184-E (confirming that the response to this request remains the same as the one previously provided to SACE and CCL in Response 3-5 of SACE and CCL's Third Data Request, Docket No. 2019-2-E); Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request 3-5, Docket No. 2019-2-E.

DESC could economically purchase power during rare reserve shortage events more economically than using its own resources in isolation.

Utilizing interchanges with neighboring utilities is important for both long-term day-ahead imports when DESC can reasonably forecast when they may be short of reserve capacity. It is also effective for short-term, real-time balancing services to supply power when it is needed due to a drop in solar output.

This is exactly the mitigation pursued by CAISO to balance solar variability in their jurisdiction. In 2014, CAISO launched the Western Energy Imbalance Market (EIM). According to CAISO,

*“The California ISO’s Western Energy Imbalance Market (EIM) is a real-time bulk power trading market, the first of its kind in the western United States. The Western EIM’s advanced market systems automatically find the **lowest-cost energy** to serve real-time customer demand across a wide geographic area. Utilities will maintain control over their assets and remain responsible for balancing requirements while sharing in the cost benefits the market produces for participants. Since launching in 2014, the Western EIM has enhanced grid reliability and generated cost savings in the millions for its participants. Besides its economic advantages, the **EIM improves the integration of renewable energy**, which leads to a cleaner, greener grid.”³⁴ (emphasis added)*

Over the past five years, the EIM has continually attracted more participants and will soon cover most of the Western Interconnection, as illustrated in Figure 5 provided by CAISO. Since its inception, the EIM has reduced costs by 736 million dollars.³⁵ In the second quarter of 2019, the EIM reduced flexibility reserves by 45% and reduced renewable curtailments by 132,937 MWh.³⁶

³⁴ See Western Energy Imbalance Market (last accessed Sept. 20, 2019)

<https://www.westerneim.com/Pages/About/default.aspx>.

³⁵ See Western Energy Imbalance Market, Benefits (last updated July 31, 2019)

<https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx>.

³⁶ California ISO, *Western EIM Benefits Report*, Second Quarter 2019 (July 31, 2019) available at

<https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ2-2019.pdf>.

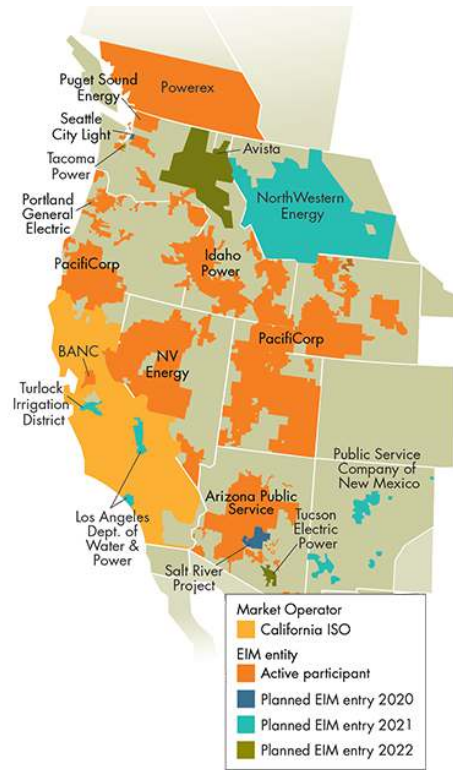


Figure 5: Western Energy Imbalance Market Participants

Recommendation: The Commission should direct DESC to model their system accurately, including the economic and reliability interchange between regions. DESC should model neighboring balancing areas to the same level of detail in the production cost analyses to accurately capture the benefits of interchange. At a minimum, DESC should use “proxy-generators” to simulate the availability of economic imports and exports in subsequent variable integration analyses.

4 Alternative reserve resources were not adequately evaluated

The Navigant study calculated the cost of providing solar reserves using changes to operating practices. This includes turning back generation to lower loading levels to increase available “headroom,” committing additional units, and making quick-start resources available to respond when necessary. While the report claimed to evaluate additional resources for reserves (new combustion turbine and battery energy storage equipment), the analysis was not comprehensive and lacked the detailed analysis required to properly conclude that alternative mitigations were not economic.

In addition, the Navigant report did not evaluate potentially valuable technologies and changes to operating practices that may be available to DESC, especially when considering a 13-year planning horizon (2020-2032).

4.1 Additional existing demand resource resources are available

The PROMOD case results include 100 MW of Interruptible Load as available reserves in all hours. The Cost of Variable Integration report states that “DESC also has 100 MW of interruptible load that can be used to meet reserve requirements.”³⁷ (page 9)

DESC’s Integrated Resource Plan states that “[DESC] has over 200 megawatts of interruptible customer load under contract. Participating industrial customers receive a discount on their demand charges for shedding load when DESC is short of capacity.”³⁸ (page 14)

When asked why only 100 MW of interruptible load was included as available to meet solar forecast error reserve requirements DESC responded that VACAR requires DESC to maintain 200 MW of contingency reserves and that “[p]ursuant to VACAR requirements, up to one-half of this reserve generation capability, or approximately 100 MW, may be met by interruptible load” . . . “[DESC] does not believe it would be appropriate, prudent, or reasonable to rely upon interruptible load to meet its need for daily operating reserves used to follow load and smooth generation.”³⁹

Although the type of demand response DESC currently has may not be appropriate for “daily operating reserves used to follow load and smooth generation,” it is the type of reserves required to facilitate solar generation integration. The Navigant report identified a need for reserves to cover infrequent reserve shortfall events. Further, these are reserve shortfall events; additional reserves are needed to stand ready to respond. Actual response (deployment of the reserves) will be required much less frequently, making interruptible load an ideal provider of this type of reserve.

³⁷ Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), Cost of Variable Integration, Navigant Consulting, August 2019.

³⁸ 2019 Integrated Resource Plan, SCE&G, 2/8/2018, available at <https://dms.psc.sc.gov/Attachments/Matter/9f865fe4-f830-4ccd-af0b-9ee5bcb25c10>.

³⁹ Response to South Carolina Conservation League and Southern Alliance for Clean Energy First Data Request 1-19, Docket No. 2019-184-E (confirming that the response to this request remains the same as the one previously provided to SACE and CCL in Response 3-21 of SACE and CCL’s Third Data Request, Docket No. 2019-2-E); Response to South Carolina Conservation League and Southern Alliance for Clean Energy Third Data Request 3-21, Docket No. 2019-2-E.

Lastly, DESC has control over the order in which resources are deployed when reserves are called on. Given the type of interruptible loads available, DESC can make these resources the “reserves of last resort.” The load would be called on if, and only if, all the available reserves from hydro, pumped storage, CC gas, and CT gas were already deployed, and more response was required. This type of reserve is especially useful for rare events. If DESC found that the interruptible loads were called on too frequently, they could then choose to commit additional units to provide reserves when necessary. This would mitigate any risks associated with relying on interruptible loads too frequently.

Recommendation: The Commission should direct DESC to count the additional 100 MW of interruptible load that VACAR does not permit DESC to count towards the contingency reserve obligation as being available to help integrate solar generation.

4.2 New battery energy storage and CT units were not evaluated properly

The only alternative mitigation strategies explicitly evaluated by DESC and the Navigant *Variable Integration Cost* study were new battery energy storage and combustion turbine (CT) gas units. According to Dr. Tanner’s testimony the analyses concluded that,

*“At this time, adding additional resources **solely to provide reserves** is not a cost-effective approach to lower the variable integration costs of the current and expected solar generation. The amount of 1-hour battery storage that can be added for the additional system costs of approximately \$73.2 million is approximately 95 MW assuming future improvements in technology and cost declines through 2025. The amount of CT gas capacity that can be added is approximately 110 MW. Neither of these capacities is sufficient to provide the reserves needed to integrate the solar generation.”⁴⁰ (emphasis added)*

The conclusion is flawed because it did not evaluate whether the new resources such as battery storage could be economic if utilized **for reserves as well as other use cases**. In actual operations these resources would be utilized for energy (shifting), firm capacity, other ancillary services (contingency reserves, voltage support, black start capability, etc.), and potential transmission and distribution upgrade deferral. While the battery storage duration would have to be increased to at least 4-hour duration to provide all these services, it may be more economic than the 1-hour reserve only asset.

In addition, if the solar PV variability and forecast errors were properly evaluated in DESC’s Integrated Resource Plan as opposed to a separate, discrete analysis, it may have changed the preferred generation expansion plan. For example, instead of procuring a new combined cycle asset for capacity and energy needs, the IRP analysis may have selected a more flexible resource mix to cover solar variability and forecast errors. This is especially true as increased solar PV integration decreases the need for baseload energy in future years.

When evaluating alternative resources for reserves, those resources should be evaluated across all the services they can provide rather than isolating them as reserve only resources.

⁴⁰ Direct Testimony of Matthew W. Tanner, Ph.D., Docket No. 2019-184-E.

4.3 Alternative mitigations are available, but were not evaluated

In addition to the existing resources, new battery energy storage, and new CT mitigations outlined above, there are several other mitigations to managing solar variability and forecast errors that were not evaluated by DESC or the Navigant report. These mitigations may be economic today or within the 13-year horizon evaluated by the *Variable Integration Cost* study.

Larger Balancing Area Coordination: As discussed in Section 3.4, DESC is interconnected with neighboring balancing areas and there are regular interchanges between them. In addition to the interchange of electricity, DESC also shares reserves with neighboring balancing areas. Currently, DESC shares contingency reserves with other members of VACAR reserve sharing group, including Dominion Energy (Virginia Power), Duke Energy Carolinas (DEC), Duke Energy Progress (DEP) and Santee Cooper.

This reserve sharing agreement for contingency reserves (immediate loss of the largest generator) has long been recognized as an economic way to mitigate rare emergency events. A similar construct could be implemented for operating reserves for solar variability and forecast errors. This would benefit from larger geographic diversity of solar resources and a larger pool of available reserve resources. If preferred, it could also be structured so that only reserves for the largest solar forecast errors are shared between the different balancing authorities, while smaller forecast errors are managed locally.

While it may take time to negotiate an expansion of the VACAR reserve sharing agreement, it is certainly plausible in the horizon evaluated in the *Variable Integration Cost* study. If neighboring balancing areas are also integrating increased solar power, they may have a similar interest in additional operating reserves. It would be reasonable and prudent to mitigate any solar integration challenges collectively.

It should be noted that a reserve sharing agreement is not required to use the interchanges more effectively. DESC can currently purchase spot energy when it is low on operating reserves. This would free up headroom from a DESC generator, which could then provide reserves.

New Demand Response: Not only did the *Variable Integration Cost* study not adequately include existing demand response resources, it also ignored the possibility of new demand response to support solar balancing. While DESC may not be comfortable utilizing existing interruptible loads for daily load following, newer demand response products are increasingly flexible and designed to be utilized on a regular basis to provide reserves. Solar operating reserves are designed to cover rare events and most of the time there is sufficient reserve capability on the system. This is an ideal scenario for demand response which would not be activated on a regular basis. In addition, costs for this type of demand response are falling due to technological advancement of sensors, load control and communication. As a result, it should be considered as a future resource in a 13-year horizon study.

Capabilities of Current Solar Inverters: When discussing options for dealing with solar impacts on the power system the *Cost of Variable Integration* report states:

"Note that there are methods for solar units to provide flexibility and ramping to the system. Although this may be a feasible alternative in the future, this

possibility has not been considered in this analysis because DESC cannot implement it unilaterally but only with technological changes by the solar facility owners.”⁴¹ (page vi)

All new solar plants greater than ~1 MW could easily be placed on automatic generation control. This is not a technology or implementation cost issue. DESC is in control of the interconnection process and simply must develop technically justified requirements with fair compensation. All parties should benefit when the power system is economically optimized and reliably operated.

It should be noted that this is a relatively expensive practice to do on a regular basis as DESC incurs an opportunity cost - if solar is curtailed to operate as an AGC resource it's zero marginal cost is replaced by a more expensive resource. However, it is an additional tool that DESC could have to use if necessary, during rare, short-term reserve shortfall events or if curtailment is occurring due to other reasons.

Upgrades to Combined Cycle Generators: While the Navigant *Cost of Variable Integration* report included a cursory evaluation of new CT units to provide reserves, it did not evaluate whether modifications to the existing Combined Cycle generators could be done in a cost-effective manner. For example, the CC units could be modified to have lower minimum stable operating levels, faster start-times, or higher maximum capacity. Each of these could increase the reserve capability of the existing CC fleet.

In addition, some of these modifications only require a change to the underlying software and controls for the plant. For example, the maximum output of the plant can oftentimes be increased via a software change that relaxes the allowable maximum generating point. Operating at these higher points may increase degradation on the equipment but would only be done during very rare events when solar significantly drops off unexpectedly. Therefore, the plant could increase its reserve capability but rarely, if ever, operate at the higher loading level. If DESC was able to increase the max output of the CC generators by 5%, it could increase reserves by 95 MW nearly every hour of the year.

Discounting solar forecast: In addition to the new investments outlined above, there are other operational mitigations available to DESC that were not evaluated. At times it may be prudent to discount the solar forecast used for generator scheduling decisions with more conservative estimates. For example, if the solar output for the following 4-hour period is expected to be 500 MW, it may make sense to use 200 MW for the unit scheduling decisions, even though it would produce a less accurate forecast.

This is because forecast errors have asymmetric costs on system operations. For example, if 200 MW of solar is forecasted, but 500 MW shows up (+300 MW forecast error), DESC has the option to back down committed generators to lower loading levels, sell the surplus energy on the spot market to neighboring utilities, or at worst curtail the surplus solar. On the contrary, if 500 MW of solar is forecasted, but only 200 MW shows up (-300 MW forecast error), then DESC

⁴¹ Direct Testimony of Matthew W. Tanner, Ph.D., Exhibit No. (MWT-2), Cost of Variable Integration, Navigant Consulting, August 2019.

only has the option (according to their analysis) to quickly ramp up committed generators, turn on expensive peaking generation, or have a reserve violation. This could be significantly more expensive than the positive forecast error despite being the same magnitude.

As a result, DESC should evaluate whether the use of an unbiased forecast error is most economic for actual commitment decisions. It should be noted that this option can be used sparingly, specifically when solar forecast reserves are expected to be scarce.

Recommendation: The Commission should direct DESC to evaluate whether larger balancing area coordination, new demand response, AGC capabilities of solar inverters, upgrades to combined cycle units, or discounting solar forecasts are economic mitigations for operating reserves.

5 Variable integration charges are fundamentally flawed

Despite the inappropriately high reserve requirements, the modeling methodology concerns, and the inadequate analysis of alternative reserve resources, there is a more fundamental problem with the Variable Integration Charges. The proposed Variable Integration Charge analysis only evaluate a relatively small operating cost and ignores a comparison to larger benefits (including avoided costs, environmental and economic benefits). The analysis also singles out a single resource type and ignores other aspects of grid inflexibility.

No generation resource is perfect. For example, nuclear generators are attractive because of their low marginal energy cost, but they are inflexible, do not follow load well, can't provide contingency reserves, and pose potential safety risks. A power system with only nuclear units would be inoperable. Many conventional thermal generators are more flexible than nuclear units but have high minimum loads and long startup and shutdown times. However, conventional generators are not typically assessed integration charges despite their high minimum loads, long startup times, or inflexibility.

When assessing the impact of solar generators on power system operations, the Company and Commission should take a similar approach as they do to conventional generation: integration charges may not be appropriate unless they are assessed on all technologies. Are integration charges being considered for solar generators only because they are the latest addition to the generation fleet and not owned by the utility? Would a new thermal generator, even a new combined cycle generator, be assessed an integration charge for its high minimum load or its long startup time? DESC proposal to assess a variability integration charge on solar generators is especially discriminatory because it is largely based on excessively long four-hour forecast error, which the Company claims is required even though the Company states that most combined cycle plants only require two hours to start.

It may be more appropriate simply to recognize that each generation technology has limitations and to then optimize the power system around those limitations. This is the role of integrated resource planning. Alternatively, maybe all generation technologies should be assessed charges to the extent that they fall short of perfection.

6 Conclusions and Next Steps

This report highlighted several problems and limitations related to DESC's proposed variable integration charges and the supporting Navigant *Cost of Variable Integration* report. These included inappropriately high reserve requirements, several modeling methodological concerns, and inadequate evaluation of alternative reserve resources. These limitations and errors should be corrected before determining whether any solar integration charge is warranted.

The methodology presented in the August 2019 DESC *Variable Integration Charge* report is flawed, and the resulting solar integration charge is unjustified. Of even greater concern, it raises the possibility that DESC will not follow best practices in forecasting and operating its fleet to integrate low-cost renewable energy. The proposed methodology is not based on a realistic estimation of operating reserve costs because it is not aligned with current operating practices which do not include any reserves for installed solar capacity, solar aggregation was not properly included, the 4-hour ahead forecast is two to three times longer than will be required with DESC's mix of conventional generators, and it utilized an overly stringent 99% confidence interval for the reserve requirement.

The analysis also used an unrealistic and inappropriate fixed solar reserve requirement, imposed 8760 hours per year. The analysis method of "blending" results from production cost modeling runs with different reserve requirements does not fix the problem. Additional reserves currently available from the Fairfield pumped storage plant and from interruptible load are appropriate for the solar reserve response but were not appropriately modeled. In addition, neighboring power systems were not evaluated correctly, even though they could be an economic way to balance solar resources and provide reserves.

Finally, the study only included a cursory examination of alternative reserve resources. It did not properly evaluate new battery energy storage and CT units because those resources were evaluated solely for reserves even though additional uses cases are likely. The analysis also ignored additional mitigation options including larger balancing area coordination, new demand response, AGC capabilities of solar inverters, upgrades to combined cycle units, and discounting of solar forecasts.

To remedy the imitations in this study, DESC should reanalyze the proposed Variable Integration Study. A good opportunity for this is the required "Grid Integration" study in South Carolina H.B.3659, which requires "an independent study to evaluate the integration of renewable energy and emerging energy technologies into the electric grid." This study would serve as an improved starting point for beginning to evaluate variable integration costs as they relate to other grid integration topics, including the benefits of integrating increased renewables and emerging energy technologies like battery storage.

DESC should also consider utilizing a Technical Review Committee (TRC), composed of outside experts on variable renewable integration. TRCs have been successfully used by many utilities to help provide independent guidance on their integration studies and to utilize the latest and best

integration study practices.⁴² The Energy Systems Integration Group has published guidelines for TRC involvement in renewables integration studies.⁴³

As a result, the Commission should consider whether any integration charges are just and reasonable. Given the significant problems with the Dominion Cost of Variable Integration study approach and analysis, as outlined in my testimony and attached report, the Commission should not approve Dominion's proposed variable integration charge at this time. The utility should revise its approach to address the problems identified and hold off on any integration charge until these concerns have been addressed and the utility has gained more operational experience is gained so that actual charges are not based solely on simulations.

⁴² For example: Idaho Power, Portland General Electric, Arizona Public Service, BC Hydro, Public Service Colorado, Pan Canadian Wind Integration Study, ISO-New England, PacifiCorp, Public Service of New Mexico, SMUD, the Western Wind and Solar Integration Study, Eastern Wind Integration and Transmission Study.

⁴³ See Utility Wind Integration Group, NREL, Principles for Technical Review Committee (TRC) Involvement in Studies of Wind Integration into Electric Power Systems (May 2009), *available at* <https://www.esig.energy/resources/principles-trc-involvement-wind-integration-studies/>.